



## A FRESH LOOK AT CONTAINMENT SEALS AND EQUIPMENT

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## ABSTRACT

The need for reliable and safe sealing of rotating equipment remains as a primary concern for industry. In situations where single mechanical seals were used the introduction of environmental and safety legislation brought about the introduction of containment sealing arrangements to control and minimise the likelihood of process fluids reaching the atmosphere. While in principle this would seem to be an ideal solution the reality is that containment seal philosophy is not readily understood and there have been notable incidents where containment seals have not performed as expected when process upsets have occurred. Given that there is a wide choice of containment technology available dictates that different seal designs and systems plus wet and dry sealing philosophies all contribute to the confusion surrounding the application of safe and effective containment sealing.

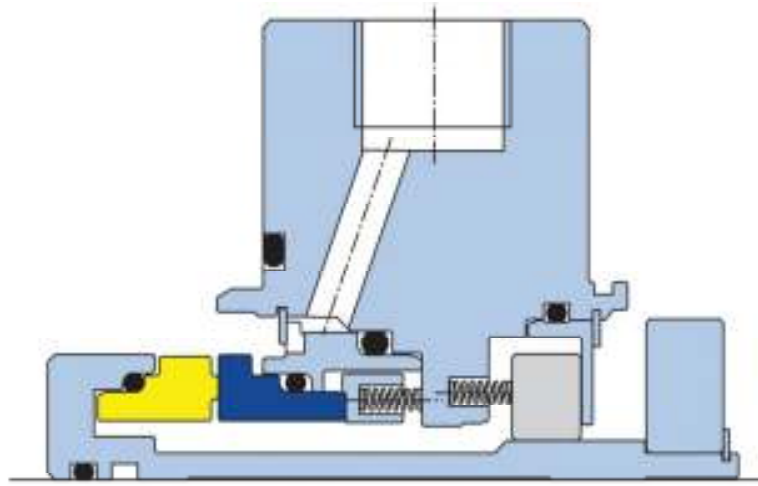
This tutorial looks at how containment seals have been applied historically and the issues that have surrounded the technology thereby questioning proper application and usage. The philosophy of dry containment seals is explained where both contacting and noncontacting containment seal options are discussed along with the associated sealing system requirements for each preference. It explains the need for introducing in-situ periodic test procedures such that containment seal functionality is not impaired during service. Finally some guidance is offered so that containment seals can be assessed and selected such that optimum performance can be assured.

## INTRODUCTION

Legislation surrounding leakages from rotating equipment sealing devices has led to more stringent regulations relating to emissions and health and safety issues. Having to upgrade single seals to more compliant technology on mature assets has evolved from being a reliability issue into effective containment or prevention of the process fluid leaking to atmosphere. In addition to selecting more modern sealing devices there is often a need to introduce or upgrade a sealing system to further manage to risk of process fluids from reaching the atmosphere through employing best practice methodology. One such instance is where dry secondary containment seals have been incorporated in addition to the primary seal faces that seal the process fluid. In particular dry containment seals have gained popularity over the past two decades or so largely because they have proved reliable in service. Specifically the refinery sector has used this technology for limiting emissions without incurring the cost of more traditional liquid dual seal systems. There is little written about monitoring of the condition of dry containment seals during operation, or how they behave in the event of high levels of leakage from a primary seal. This tutorial discusses these issues and makes comparisons with other sealing options.

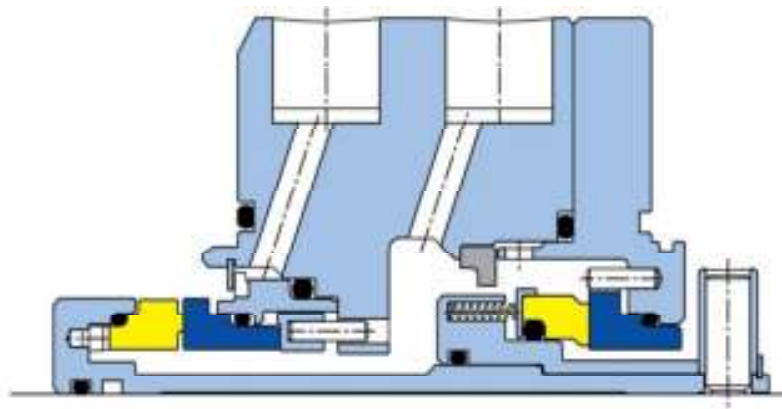
## API SEAL ARRANGEMENTS

According to API 682 [ref 1, 2] there are three types of seal arrangements. Since this standard has now been adopted in other industries it is practical to use the terminology adopted in this standard as the basis for dialogue wherever possible. In this respect we need to firstly establish the type of seal that is being treated (and which are not) in this document. API 682 states three different seal arrangements.



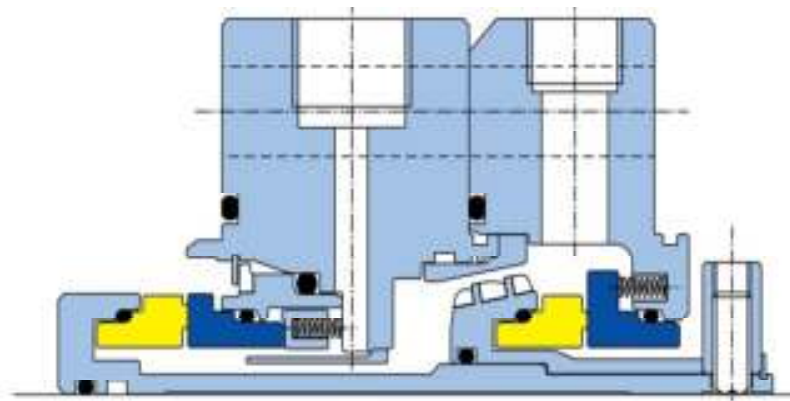
**FIGURE 1- Arrangement 1 Seal [ref 3]**

Arrangement 1 seals have one set of seal faces (i.e. one mechanical face seal interface per assembly- see figure 1). It should be noted that this type of seal arrangement can have a 'containment device' but this usually comprises of a bush type device that provides a restriction to flow rather than a sealing element. The scope of the latter is beyond the scope of this document.



**FIGURE 2- Arrangement 2 Seal [ref 3]**

Arrangement 2 seals have two sets of seal faces (i.e. two mechanical face seal interface per assembly) where the inter-stage cavity between the two sets of seal faces has a pressure less than that of the primary seal chamber (see figure 2). This seal arrangement provides leakage containment of the process fluid where the atmospheric seal can be a wet or dry running seal design. When the inter-stage cavity between the seals is fed with a liquid or gas it is termed a buffer fluid.



**FIGURE 3- Arrangement 3 Seal [ref 3]**

Arrangement 3 seals have two sets of seal faces (i.e. two mechanical face seal interface per assembly) where the inter-stage cavity between the two sets of seal faces has a higher pressure than that of the primary seal chamber (see figure 3). This seal arrangement provides prevention of leakage of the process fluid. The inter-stage cavity between arrangement 3 seals is always fed with a high pressure liquid or gas it is termed a barrier fluid.

### CONTAINMENT SEALS

A containment seal is a particular type of arrangement 2 seal where the atmospheric seal is dry running such that during normal operation the atmospheric side seal is lubricated by either process vapours (from the primary seal face), steam or gas where the latter two buffer mediums are injected into the inter-stage cavity from an external source. Historically some tandem (arrangement 2) seals had buffer liquids introduced between the two sets of seal face where again these were classified as ‘containment seals’. For completeness this document will discuss such seals in the context that some users classify these as containments seals even though current practice dictates otherwise.

Although the definition of ‘containment seal’ has changed within industry over the years (most notably different revisions of API 682) for the purpose of this document the following covers the ‘intent’ of containments seals as adopted by the vast majority of users of such devices. In the main this technology emerged from tandem seal designs where containment seals are often considered as being a particular type of tandem seal or system. They are used primarily where the leakage of process fluid directly to atmosphere has to be controlled, where some (but not necessarily all) of the items listed are the attributes offered by containment seals and associated systems-

- To function reliably for the design life of the seal (minimum 25,000 hours)
- To reduce the likelihood of process fluid reaching the atmosphere in the event of primary seal failure.
- To provide safeguard over a short period in the event of a primary seal failure.
- To reduce the amount of process fluid reaching the atmosphere during normal operation or transient operation.
- Reduction of pollution, emissions and hazards associated with the process fluid.
- Reducing the hazards associated with process fluid escape lessens plant insurance premiums.
- Reducing pollution and emissions lessens the impact of environmental impact and tariffs.
- To ensure that process fluid leakage is directed into a suitable collection device/system.
- To seal the buffer gas during normal or transient operation.
- To assist in the monitoring of the seals and associated leakages.
- To alarm in the event of a malfunction such that remedial action can be taken
- Improvements to plant housekeeping through reduction of process fluid leakage contamination.

The definition of a containment seal within API 682 has evolved to the point where the latest 4th edition provides the following- (3.1.20 - containment seal) Special version of an outer seal used in Arrangement 2 and that normally operates in a vapor (gas buffer or no buffer) but will seal the process fluid for a limited time in the event of an inner seal failure. See 4.1.4.

Where section 4.1.4 (Seal Arrangements) states

Arrangement 2—Seal configuration having two seals per cartridge assembly, with the space between the seals at a pressure less than the seal chamber pressure.

In Arrangement 2, the outer seal can be a wet seal or a dry-running seal. The inner seal utilizes a piping plan typical of Arrangement 1 seals. If the outer seal is a wet seal design, an unpressurized liquid buffer fluid is supplied to the outer seal chamber. If the outer seal is a dry-running seal it is defined as a containment seal (3.1.20); a gas buffer may be used.

API 682 summarises the distinction between the various arrangement 2 seal designs as follows:-

#### 4.1.4.2 Alternate Technology Designs and Sealing Methods

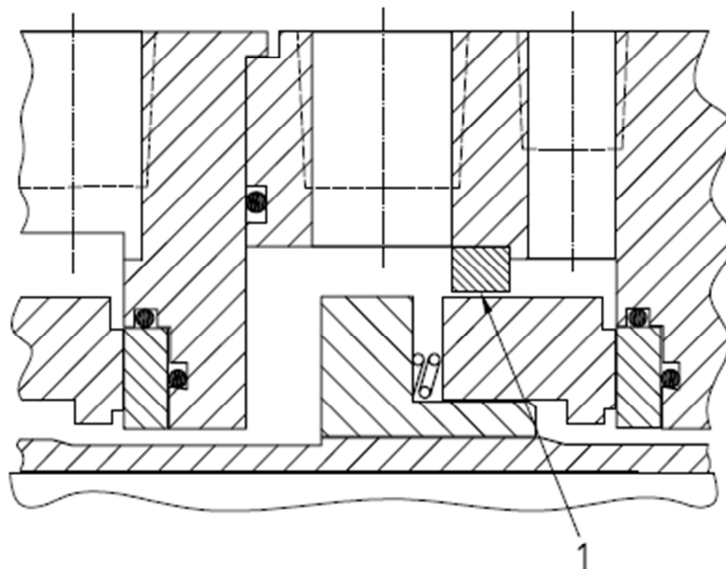
Alternative technology designs and sealing methods are also considered, as follows.

- *Contacting wet (CW) seals*—Seal design where the seal faces are not designed to intentionally create aerodynamic or hydrodynamic forces to sustain a specific separation gap (refer to 3.1.18).
- *Noncontacting (NC) seals (whether wet or dry)*—Seal design where the seal faces are designed to intentionally create aerodynamic or hydrodynamic separating forces to sustain a specific separation gap (refer to 3.1.56).
- *Containment seals (CS), whether contacting or noncontacting*—Seal design with one flexible element, seal ring and mating ring mounted in the containment seal chamber (refer to 3.1.20).

It follows that containment seals are a particular design of tandem seal where the outboard seal is designed to operate on vapours, buffer gas or steam but not usually liquid. The function of the seal enables normal operational leakage from the inboard seal to be directed and collected in an appropriate manner and also to temporally prevent or reduce process fluid leakage in the event of a primary seal failure until a safe shutdown can be conducted.

The intent to run in what can be classified as a ‘dry’ environment dictates that the seal face technology differs to that of conventional wet seals where liquids are used to lubricate and cool the seal faces. In containment seals the face technology and materials combine to allow the seal to operate dry where there are two different seal designs namely contacting and noncontacting variants, each with their own merits and limitations which are discussed below. Irrespective of the seal face design the functionality of both seals is identical, namely that they should operate in what could be loosely termed as a back-up mode during normal operation (or stand-by) and then limit process fluid leakage for a period of time in the event of a primary seal failure. To a certain extent the majority of the other attributes associated with containment seals are a function of the various piping plan options plus the properties of the process fluid itself.

A further difference between conventional arrangement 2 wet buffer seals and containment seals is that the containment faces are separated from the (leakage) vent and drain with a (restriction) bush type device (see figure 4). This allows buffer gas to be introduced directly over the containment seal face (at a slightly higher pressure than the containment seal cavity) before passing underneath the bush where it then combines with the primary seal leakage before exiting the containment seal chamber via either the vent or drain connection. This means that the leakage is kept away from the containment seal faces and is directed out of the seal gland to the collection system. Given also that the buffer gas is usually inert nitrogen it means that the process leakage emissions from the primary seal are virtually eliminated because they are guided to the collection system by the buffer gas and because the containment sealing interface is fed by inert buffer gas.



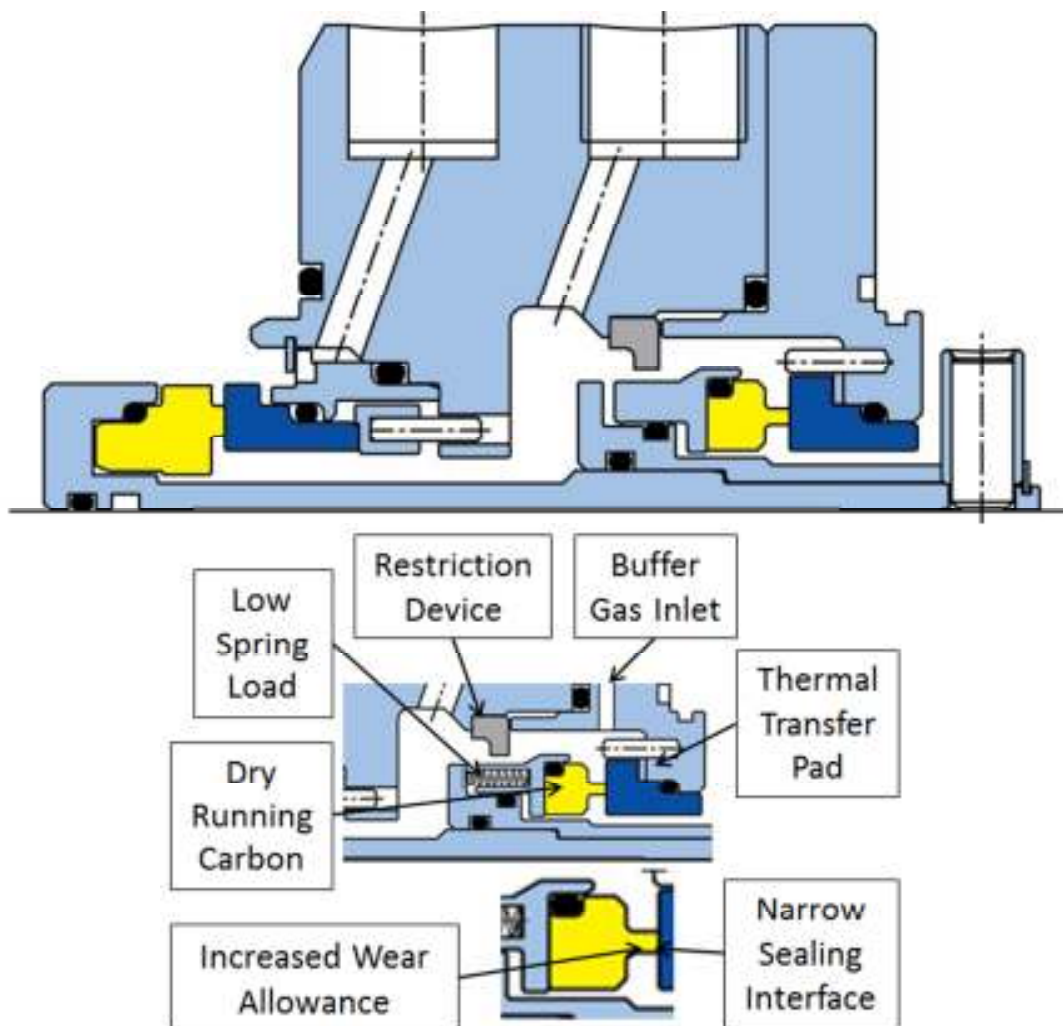
**FIGURE 4- Containment Seal Bush [ref 1]**

#### *Contacting Containment Seals*

Dry contacting containment seal designs utilise geometries and materials (Figure 5) that allow continuous contact of the secondary (containment) mechanical seal faces in a gas environment. Such seals were designed and developed to operate in gaseous environments and the expectation is that there is only usually a limited amount of fluid within the seal interface film.

The lack of fluid at the sealing interface is compensated for by using specially formulated grades of carbon with high graphite content

and break-in lubricants for the seal face material. In addition special design features such as low spring loads and narrow seal face width combine to enable dry contacting containment seals to operate at induction motor speeds. Despite these ‘special’ features there is still friction and heat being generated and the compromise is that dry contacting containment seals can only be used at low pressure and that they wear continuously at higher rates than wet seal technology.

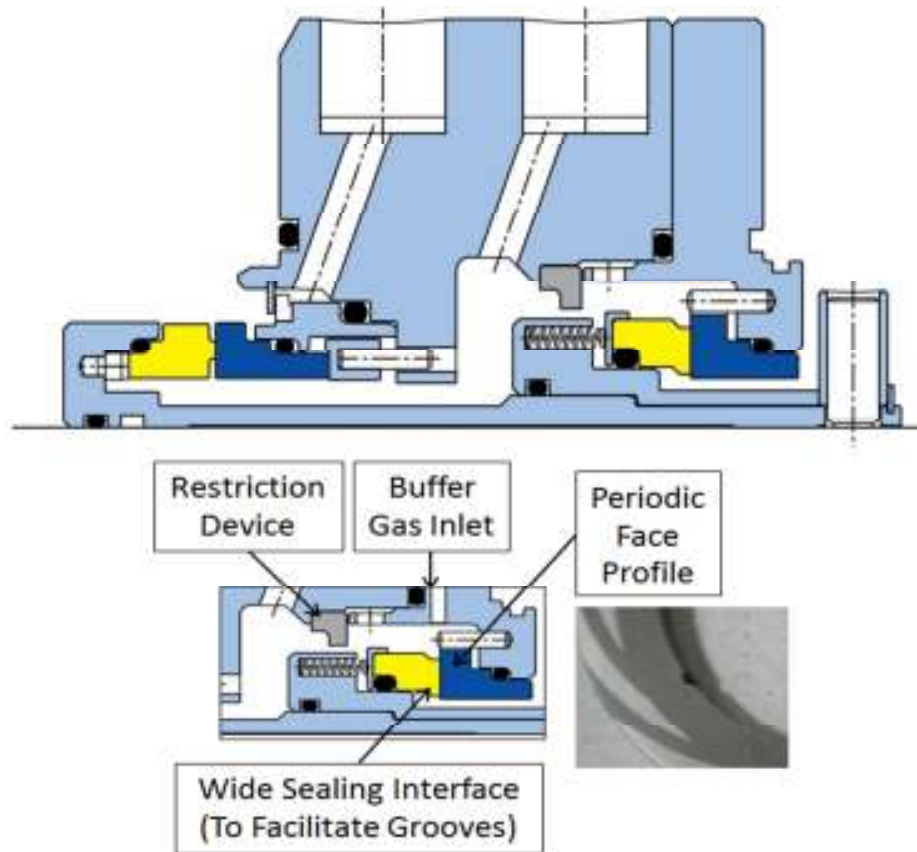


**FIGURE 5- Contacting Containment Seal (Top) & Face Detail (Bottom) [ref 3]**

Despite the low pressure limitation dry contacting seal exhibit very low leakage rates, can operate at low speeds (slow roll or lengthy start-up/coast down), can rotate in reverse (so called ‘turbining’), are more tolerant of contamination (no groove features to clog) and are generally more tolerant of liquid ingress than the noncontacting containment seal designs. On the minus side the operating pressure has to be carefully controlled (to prevent overload) where pressure spikes/fluctuations (flare line pressure spikes) need to be avoided. In addition the additional heat generation can have an adverse effect on the primary seal leakage (especially where no buffer gas is used) where residue could build up on internal seal surfaces and coking/polymerisation at the seal faces. Finally although the contacting containment seal should reach the API 25,000 hour longevity the consequences of increased wear in moist/wet environments tend to limit the service life as does its ability to reduce process leakage in the event of a primary seal failure (due to the likely pressure increase within the containment seal chamber). The latter comments are justification for having site integrity tests for containment seals.

#### *Noncontacting Containment Seals*

These tend to have periodic features (commonly referred to as grooves) on one seal face that produces localised high pressures under the influence of motion such that lift forces are produced that separates the faces such that the fluid (gas) film both lubricates and supports the sealing load making it fully noncontacting during motion (see figure 6). This eliminates contact friction and heat generation allowing noncontacting containment seals to withstand much higher pressure and higher speeds than contacting seal designs.



**FIGURE 6- Noncontacting Containment Seal (Top) & Face Detail (Bottom) [ref 3]**

The noncontacting seal design do not wear during operation and in theory have a higher service life expectation than the primary seal. Additionally they are also far more tolerant of pressure spikes that could be a result of downstream flare conditions and the absence of frictional effects dictates that process leakage during normal operation is much less likely to polymerise or coke due to thermal effects.

Despite the numerous advantages of noncontacting seals it should be appreciated that leak rates are far higher than contacting variants and the seal faces are much more sensitive to contamination since any debris and liquid that enters the grooves will impair lift generation. Given also that the lift mechanism requires motion in situations where shaft rotation is low there might be insufficient speed to produce lift resulting in a potentially damaging situation. Finally since some noncontacting seal face designs utilise unidirectional groove technology the seal will be incapable of reverse rotation.

Given the fundamental difference in which contacting (boundary lubrication) and noncontacting containment seal work means that each has its merits and limitations. When containment seals are being selected for service it is advantageous to be able to compare and understand how they are likely to operate so that they will operate reliably during normal service and provide the necessary leakage protection when the primary seal fails. The most likely differences (under like-for-like conditions) are provided in table 1.



TABLE 1- Containment Seal Comparison		
	Contacting	Noncontacting
Leakage	Low	High
Pressure Capability	Low	High
Over-Pressure Risk	High	Low
Heat Generation	High	Low
Wear	High	Low
Service Life	Limited	Unlimited
Contamination Risk	Low	High
Speed	Low	High
Slow Roll	Good	Poor
Reverse Rotation	Good	Poor (1)
Interface Lubrication	Material	Fluid
Liquid Tolerance	Fair	Low
Gas Starvation	Good	Poor
Steam Compatibility	Low	Moderate
Dry N2 Compatibility	Poor	Good
1) Unidirectional Designs Only		

Other considerations between the two technologies include ease of monitoring. Noncontacting seals will normally operate with no appreciable temperature increase and in situations where contact occurs the associated friction and sudden rise in temperature could be used to trigger alarms. Given the heat generated by contacting seal designs during normal operation small differences in temperature variation are far more difficult to detect.

## PIPING PLANS

Having reviewed the two basic seal types the focus is now on the support systems, or piping plans, that are used in conjunction with dry containment seals. There are two piping plans that cover containment seal inlet and two for outlet.

### *Inlet Plan 71*

Is normally specified when no buffer gas is supplied to the containment seal. API 682 does allow the user to operate containment seals in this way although in reality there are quite a few variations of plan 71 where the containment seal ports on the seal gland are utilised in other ways (such as fitting a pressure gauge or manual vent and valve). See figure 7.

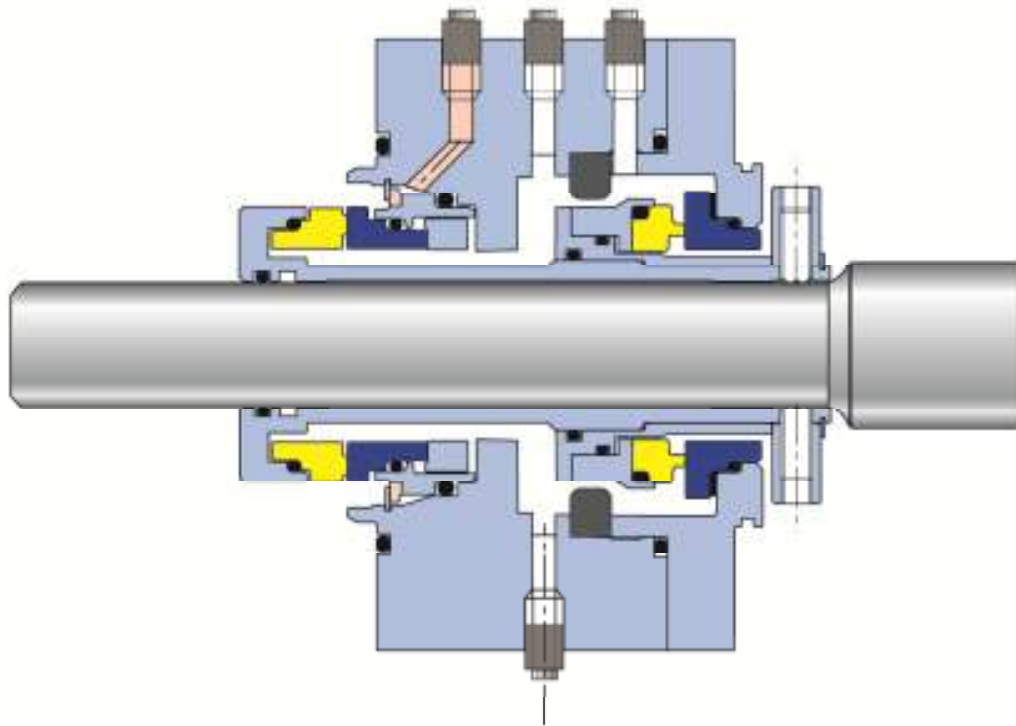
Having no buffer dictates that the containment seal cavity fills with process fluid (liquid and/or vapour) that is leaked during normal operation from the primary seal and given that the containment seal will have been developed for use with dry gas this could cause issues. This also dictates that the containment seal is directly exposed to process fluid and hence the emissions from the seal could be no better, or even worse, than an arrangement 1 seal. A further consequence of having process fluid present in the outboard sealing interface is that coking or polymerisation may occur at the atmospheric side of the interface.

Despite the limitations of having no gas inlet this piping plan can be used on clean duties where no phase change is expected when the primary process seal leakage is able to exit the containment seal cavity without issue.

If the seal is a containment seal is a contacting type then any condensing primary seal leakage dictates that the containment seal cavity fills with process liquid. This can mean that the additional heat generated by the secondary seal faces causes the process fluid to polymerise and coat the exposed surfaces of the seal thus clogging components and impairing operation.

If the seal is a noncontacting design there are similar issues. Firstly given that a pressurised fluid film is a design feature the leakage emitted from this type of seal is greater than that of conventional seal faces and significantly more than that of contacting containment seal faces. In other words the emissions could actually be greater than with other seal designs. In duties where the process fluid leakage is condensing the cavity has liquid present and this can be harmful for the lift features (grooves) on the noncontacting seal faces. The presence of fluid causes the interface to become much hotter which may have damaging consequences and any debris could clog the shallow face grooves (which are normally only microns deep) resulting in lift generation being lost altogether. Similarly there

could be issues when the leakage from the primary seal is minimal. Given that a noncontacting seal needs a plentiful supply of gas in order to operate correctly then insufficient leakage may result in gas starvation at the interface and the lift produced will be reduced accordingly.



**FIGURE 7- API Plan 71[ref 3]**

Clearly the absence of a buffer gas means that the containment seal operates in a process fluid enriched environment. The consequences of this both during normal operation and eventual primary seal failure need to be carefully considered. The operation of the seal on duties with condensing and vaporising primary seal leakage need to be carefully considered, as does the containment seal type since contacting and noncontacting designs both have issues that cannot be overlooked. The absence of a buffer gas dictates that the containment seal interface film will be process fluid and there could be problems with process fluid residue and deposits forming within the containment seal cavity and on exposed seal surfaces which could compromise seal functionality. Given that the (normal) operating conditions for the containment seal are a function of primary seal leakage and that said leakage may be variable by nature then this would make containment seal functionality difficult to monitor and evaluate to the extent that there are doubts regarding whether the containment seal will be able to provide any type of restriction when the primary seal fails.

#### *Inlet Plan 72*

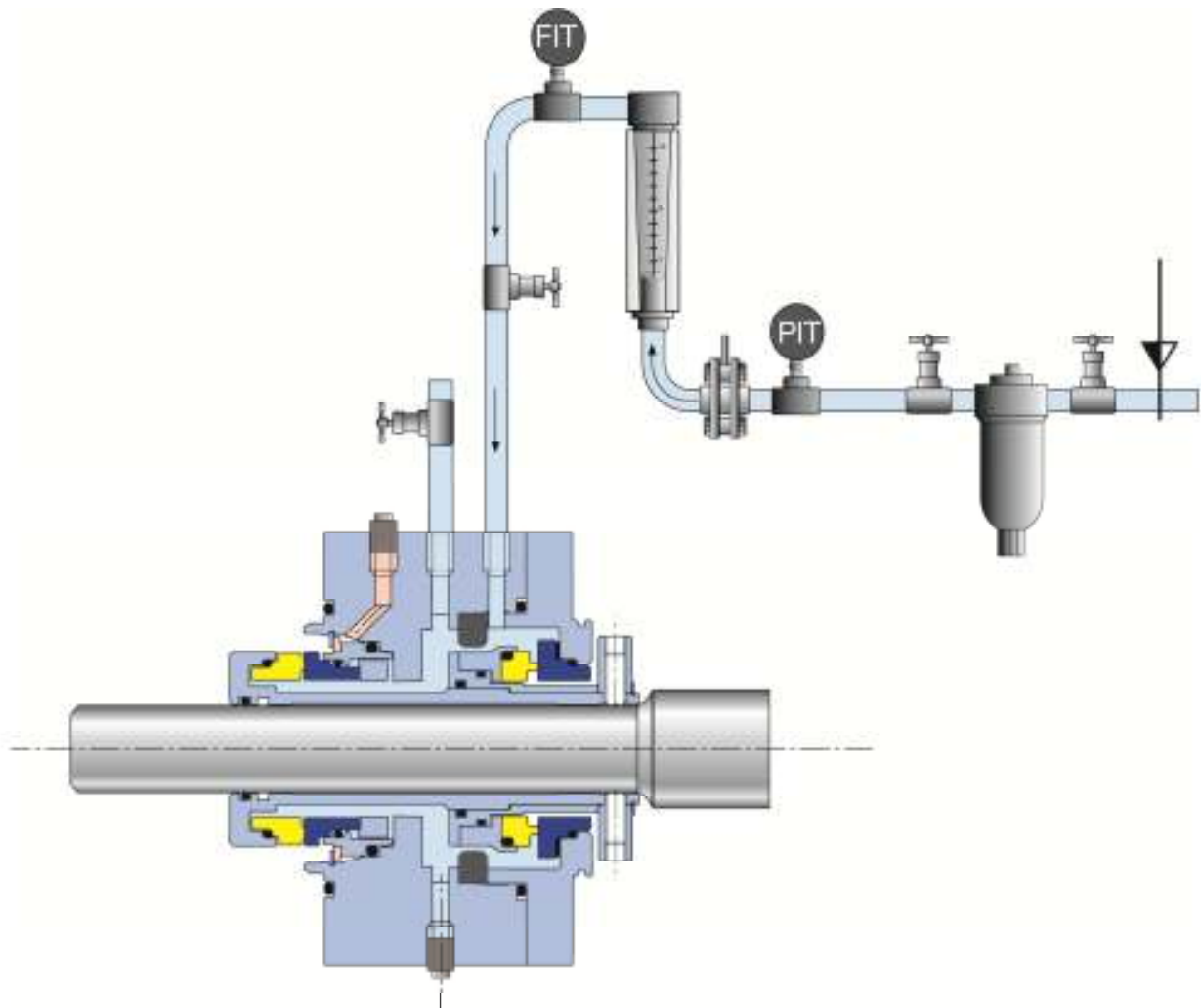
This piping plan is used to describe the introduction of a buffer fluid into the containment seal. Although the manner in which API 682 describes this plan implies an inert gas that is being injected it also covers steam and other media. On plants where plan 72 systems are in use it is common for the buffer gas introduction to be described as the 'sweep gas' or 'nitrogen sweep' due to the manner in which it passes through the seal cavities. See figure 8.

A typical plan 72 (as depicted in API 682) involves buffer being introduced into the seal gland, usually at not more than 70kPa. The buffer enters the seal over the containment seal faces and the containment seal design has a restriction between the buffer inlet and the containment seal cavity such that the fluid immediately surrounding the containment seal faces is buffer fluid. This ensures that the gas entering the sealing interface is clean buffer gas that has not been contaminated by process fluid. Once the buffer passes through the restriction device it mixes with the process fluid leakage from the primary seal (see figure 4).

Given that API 682 plan 72 dialogue is based upon buffer gas (as opposed to other media) many seal vendors have standard panels that replicate 682 requirements. The major components for such a system are (in sequence) an isolation valve at the panel inlet followed by a coalescing filter (which in itself assumes that the intent is that there should be a gas and that it should be moisture free). There is then a forward pressure regulating valve, pressure transmitter (with local display) and an orifice. This set up allows the correct flow to be controlled through the seal/system. Normally the pressure transmitter is alarmed and set to an alarm point based



upon the outlet plan system (marginally higher than flare pressure. This again implies that there should be an outlet system despite the standard stating that a plan 72 can be used alone or in conjunction with a plan 75 or 76. The orifice both isolates the regulator/transmitter from the outlet system thereby enabling the two to be set without being influence by the outlet and also restricts

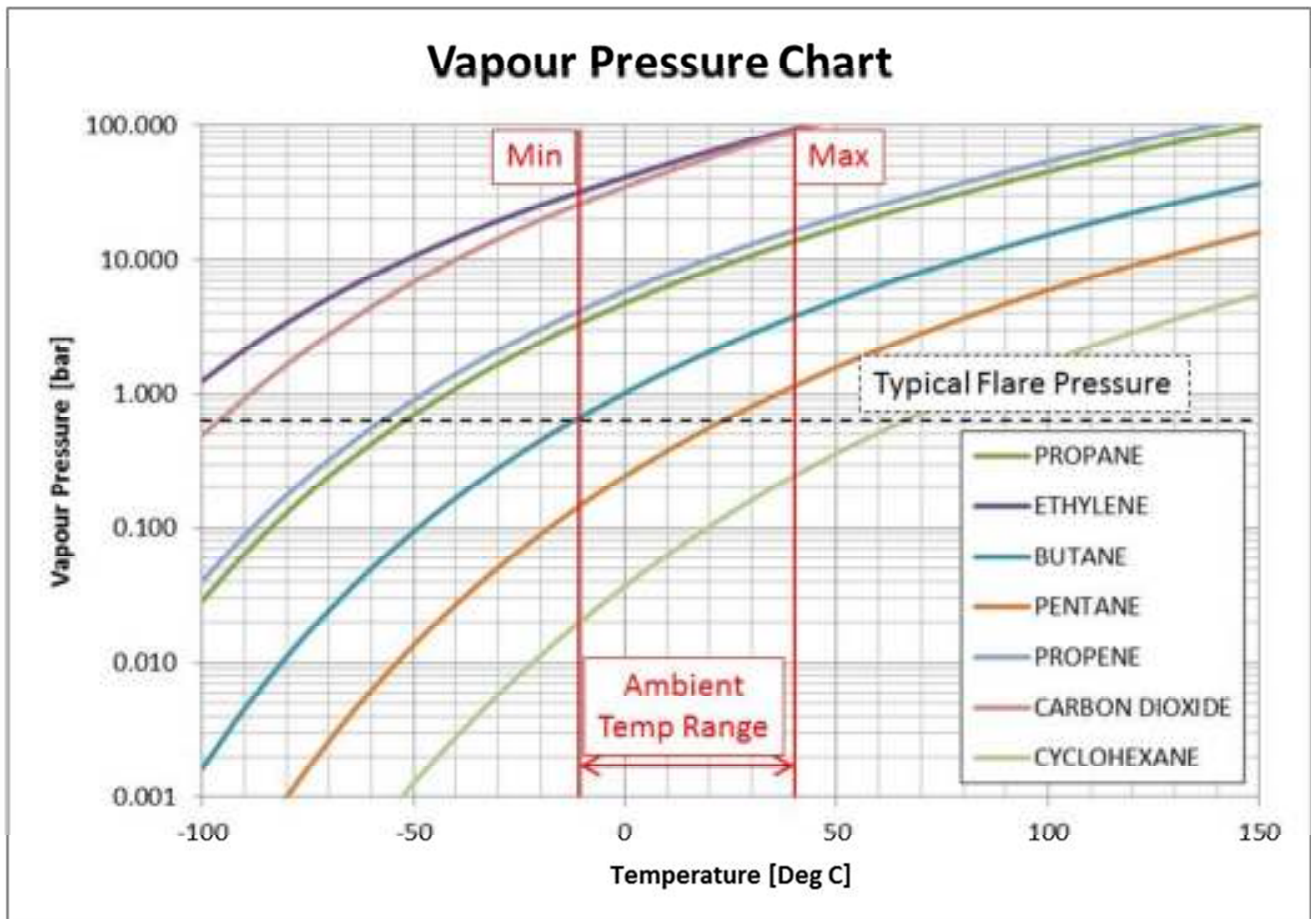


**FIGURE 8- API Plan 72 [ref 1]**

flow in the event of a containment seal failure (where inlet gas flows/loss would otherwise be uncontrolled). There is also a flow transmitter and a check valve prior to the inlet piping going to the seal. Many systems also have a further isolation valve and a vent/drain at the 72 panel outlet such that the system can be fully emptied and isolated in the event of maintenance work being necessary.

Where steam is selected as the buffer it may require some additional features to enable the seal to function correctly. The actual features required will be influenced by the containment seal design (contacting or noncontacting), the outlet plan/conditions and, to a lesser extent, the nature of the primary process seal leakage. On contacting seal designs the moisture in the steam may be unsuitable for the grade of carbon used for the containment seal face which could wear excessively. On noncontacting designs the steam should be prevented from condensing within the containment seal chamber otherwise steam condensate could fill the grooves and reduce lift capacity. If the intent/requirement is to use steam as the buffer fluid then it is advisable to consult the seal vendor to identify what additional features or equipment is required to ensure optimum performance for the seals.

A well devised plan 72 gas inlet provides a controlled environment for the containment seal to operate. This should not be underestimated since it dictates that the containment seal operates under the type of conditions that they were originally designed and developed. Given that the gas will be clean and dry having a plentiful supply of buffer passing over the containment seal will provide a certain degree of cooling and also dictate that no process fluid emissions are released to atmosphere. Having a controlled buffer inlet source also provides a stable operating environment for the containment seal and provides datum on which instrumentation and alarms can be established plus it also means that monitoring and troubleshooting is easier. While there are many merits in adopting a controlled buffer inlet one thing that needs to be carefully considered is the most suitable outlet because ‘what goes in must come out’.



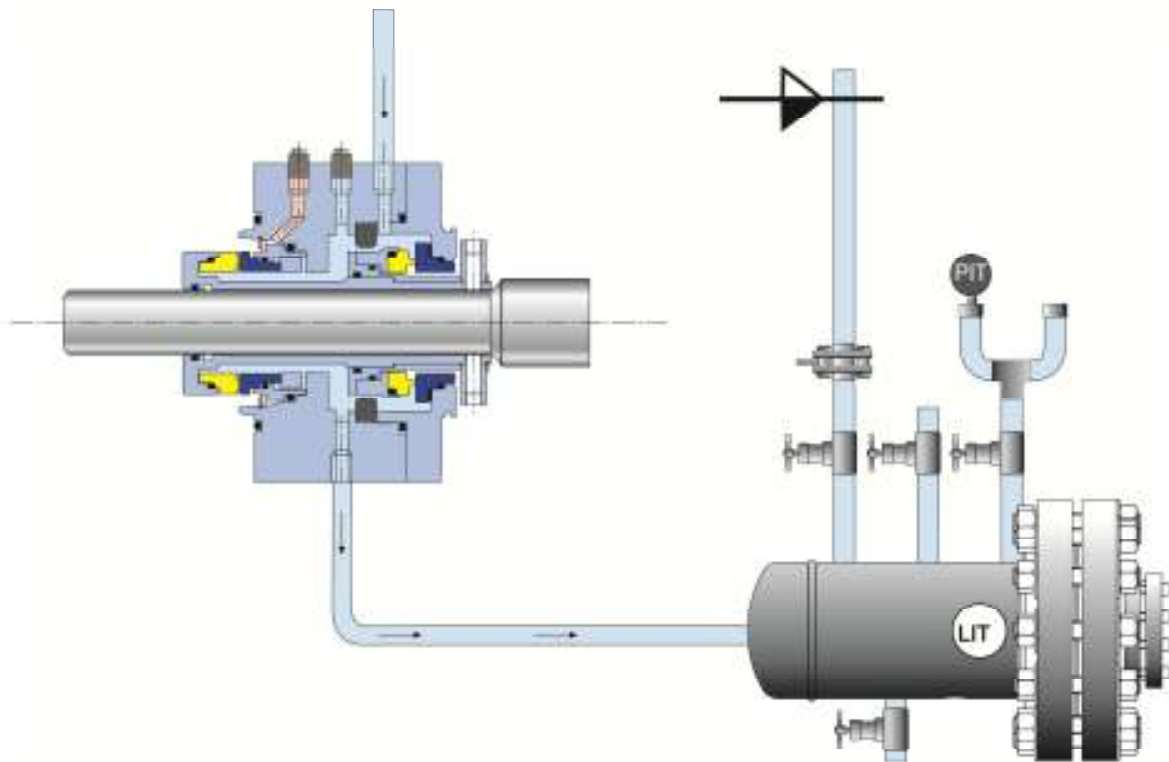
**FIGURE 9- Vapour Pressure Graph For Selected Hydrocarbon Fluids [ref 3]**

API 682 states that this plan may be used with or without outlet plans however failure to provide an (adequate) outlet other than the containment seal interface effectively ‘dead ends’ the containment seal cavity. It should also be noted that the outlet plan alarm setting forms the basis for setting the inlet control valve hence the lack of an outlet may complicate pressure control valve set up. This would produce a situation where the buffer gas within the containment seal cavity would become enriched with process fluid leakage from the primary seal. If left undetected this would produce a potentially damaging condition within the containment seal cavity due to pressure and thermal overload of the containment seal.

#### *Outlet Plan 75*

This plan is specifically aimed at applications where the primary process fluid leakage during operation is expected to be a condensing liquid (or mixed phase). Figure 9 shows a chart where the vapour curves for various hydrocarbon fluids are represented. The aim of such charts is to identify the likely phase condition of the process fluid as it would be upon exiting the primary seal faces (note that ambient effects need to be factored in to account for actual conditions). A plan 75 system is shown in figure 10.

The leakage from the primary seal tends to fill the containment seal cavity however a combination of the inlet piping plan, seal cavity design, outlet port position and gravity will cause the leakage to exit the seal and flow into a collection vessel. The vessel design and all of the associated fittings should be rated/certified to the maximum process conditions (MAWP & temperature) because under adverse conditions the containment system could be subject to such loads.



**FIGURE 10- API Plan 75 [ref 1]**

Many seal vendors have devised plan 75 collection vessels using API 682 guidance. The offering includes a suitably sized (and rated) collection vessel that includes local level indication and a level transmitter such that leakage rate can be monitored and that warning can be provided as the vessel fills to the point where it should be emptied. There are usually additional connections on the vessel that allow drainage (via a normally closed valve, a pressure transmitter, a vent fitting (with normally open valve) that allows vapours to be routed to a vapour collection system. In addition there may be further connections that allow a test gas to be introduced for in-service testing (in practice this would require that the vent connection be closed for the duration of the test).

#### *Outlet Plan 76*

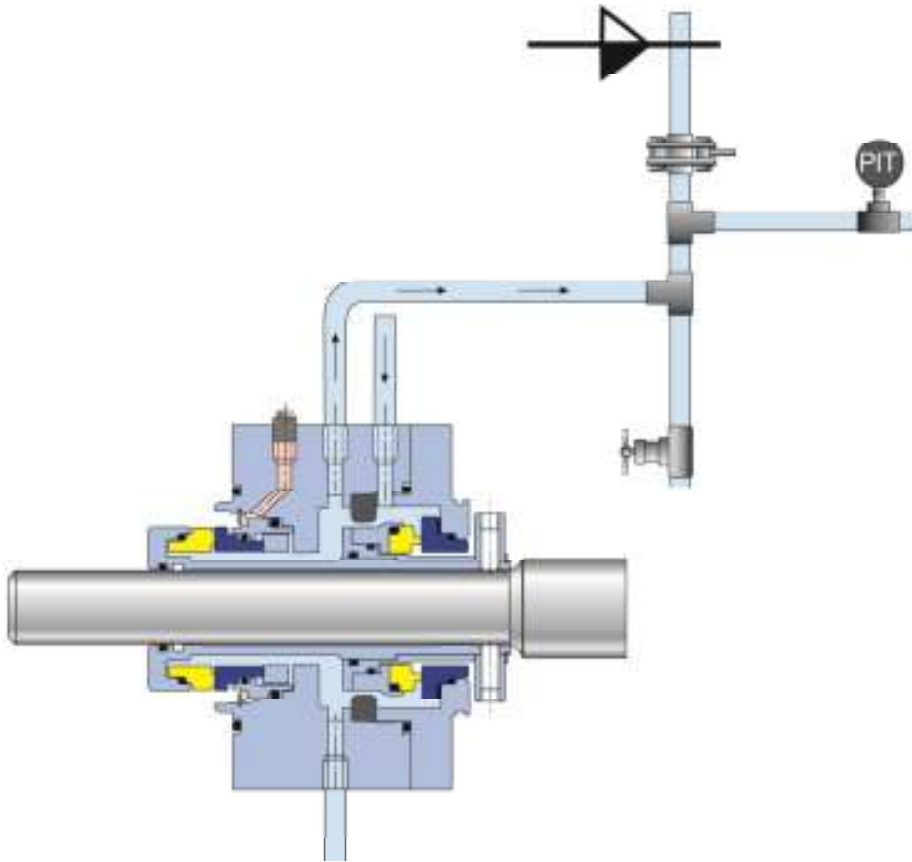
This plan is specifically aimed at applications where the primary process fluid leakage during operation is expected to be a noncondensing vapour, figure 11 can again be referenced to determine the condition of the fluid emerging from the primary seal faces.

The leakage from the primary seal tends to fill the containment seal cavity however a combination of the inlet piping plan, seal cavity design, outlet port position and the sg of the vapours will cause the leakage to exit the seal and flow into a vapour collection system. The pipework design and all of the associated fittings should be rated/certified to the maximum process conditions (MAWP & temperature) because under adverse conditions the containment piping could be subject to such loads.

Many seal vendors have devised plan 76 collection piping system using API 682 guidance. The offering includes a suitably sized (and rated) collection piping that includes a pressure transmitter, an orifice and an isolation valve before the vapour collection system (which is not included as part of a standard part of plan 76 in API 682). It is also normal for the piping immediately before the pressure transmitter to have a branch where there is a 150mm long 'down leg' with a normally closed valve. The purpose of this is to provide a location for any condensation that might be present in the vapour to collect so that it can be drained periodically. Some systems have sophisticated drainage schemes to automatically drain the down leg but for the most part this is normally done manually. The down leg feature and valve also provides a convenient location for a test gas to be introduced so that the integrity of the containment seal can be verified. Finally a check valve may also be utilised on the outlet section of piping for a plan 76 system so that fluctuations in the downstream vapour collection system will not adversely affect the containment seal cavity. Given that the pressure within containment seal cavity is low then (depending on the seal type and inlet system) care must be taken to account for the check valve cracking pressure when such a device is specified.

Using local level indication and a level transmitter dictates that leakage rates can be monitored and that warning can be provided as the vessel fills to the point where it should be emptied. There are usually additional connections on the vessel that allow drainage (via a

normally closed valve, a vent fitting (with normally open valve) that allows vapours to be routed to a vapour collection system. In addition there may be further connections that allow a test gas to be introduced for in-service testing (in practice this would require that the vent connection be closed for the duration of the test).



**FIGURE 11- API Plan 76 [ref 1]**

#### *No Standard Outlet Plan*

This can take many forms. Sometimes the seal gland connections are simply plugged however this would dictate that the containment seal cavity would fill without any form of outlet (other than the containment seal interface) This would dictate that vapours and liquid would accumulate in the cavity which once full would produce a potentially damage pressure increase and overload (thermal and pressure) of the containment seal. To prevent this sometimes a local pressure gauge and a drain valve are connected to the ports. This would enable some form of pressure monitoring of the seal cavity that would result in manual drainage once an agreed pressure level is reached. Having a high presence of process fluid leakage within the containment seal cavity also means that emissions will be higher (than if the leakage is allowed to exit) and the collected leakage could reach the containment sealing interface causing coking and polymerisation. A further issue of having no outlet is that the leakage from the primary seal may attach to the internal containment seal and gland surface to the extent that the deposits/debris actual prevent the seal and/or gland from functioning correctly.

#### **CONTAINMENT SEAL INTEGRITY TESTING**

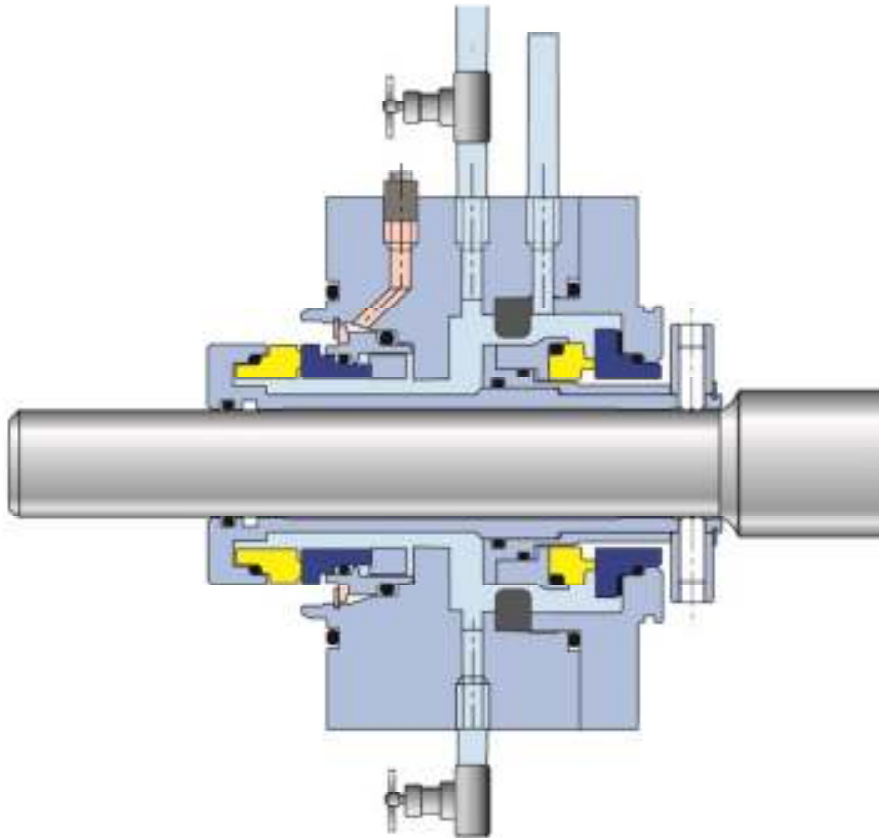
For avoidance of doubt a containment seal site integrity test should not be confused with qualification tests (API 682 10.3.2), hydrostatic tests (API 682 10.3.3), job seal test (API 682 10.3.4) and assembly integrity test (API 682 10.3.5) which are all normally conducted by the seal manufacturer. Similarly the containment seal system equipment will have undergone testing that relates to pipework and vessels which again are different to containment seal site integrity tests.

The only way to determine whether the containment seal will function correctly in the event of a primary seal failure is to engage in regular integrity tests on the containment seal. Such tests should be conducted on site by users however there is a great deal of confusion regarding how these tests should be conducted (static or dynamic), at what intervals and what pass/fail criteria should be applied. Again the number of containment permutations possible (as illustrated in table 2) add yet more confusion and almost certainly dictate that no “one” site integrity test will suit all situations.

The first thing to establish is whether the factory acceptance test provides any guidance on how the site integrity test should be conducted. Most factory tests adopt API guidelines (10.3.5) where both seals are tested statically to 175kPa (gas). Once applied the pressure source is isolated from the test rig such that any leakage will result in a pressure drop (see figure 12). The pressure drop is recorded over a 5 minute period whereby a 15kPa pressure drop is the pass/fail criteria. It should be acknowledged that in order for seal vendors to adopt a consistent pass/fail criteria for containment seals (regardless of size) that an additional volume of gas is included in the factory test loop. Without the additional volume of gas the amount of volume in a small seal would dictate that a small loss of test pressure would produce a large pressure drop whereas the same loss on a large seal would not. In this respect API 682 actually provides dialogue (but not guidance) that accounts for additional differences that mean the factory test cannot be replicated on site.

Because of variations in volume, installation, and alignment, the results of the assembly integrity test may not be repeatable after installation.

The first issue to overcome is the actual test pressure for the site test. Although a factory test is conducted using 175kPa gas this may not be practical on site. Given that most sweep gas and alarms are set to 70kPa then this might provide a more convenient test pressure since this is the pressure that the seal will be operating at in the period leading up to a primary seal failure occurring. In situations where the pressure within the primary seal cavity is zero the application of a test gas will produce a pressure reversal across the primary faces. On certain seal designs a pressure reversal across the primary faces can sometimes cause unwanted displacement of the primary seal face components so it is advisable to test at the lowest practical pressure. Alternatively if it is known that the seal can withstand pressure reversals then higher test pressures can be adopted.



**FIGURE 12- Isolation During Testing [ref 3]**

The piping plan will also have a large influence on the ability to test containment seals. Both API plan 75 and 76 have provision to introduce a test gas (via connecting a gas source to a normally closed valve on the system and opening it). In both cases there is also a pressure transmitter (with local readout) that could be utilised to monitor pressure during testing plus isolation valves but in both cases there will be a largely unknown volume to account for when establishing a suitable pressure drop for the test period. With regard to the latter point then since most API integrity tests are conducted over a 5 minute period then it would make sense to use the same time period for site integrity tests.

In a typical site integrity test it needs to be understood that the primary seal will also play a part in the results/trends observed. If the primary seal cavity is pressurised then there will be a certain amount of leakage across the face which will add to the amount of fluid in the containment seal chamber. The introduction of the fluid could actually increase the pressure within the containment seal cavity. Similarly if the process fluid within the pump is hot (or cold) when the site integrity test is conducted the heat soak through the gland may also cause pressure variations which could be wrongly interpreted during the test.

Many sites where containment seals are used adopt their own test regimes whereas others put no such measures in place. There is a wealth of evidence [ref 4] to suggest that a great many containment seals do not contain leakage when the primary seal fails. Although suitable site integrity testing may safeguard such events it does need to be appreciated that a successful site integrity test only ensures sealing integrity at that particular instance in time. Having stated that it also needs to be appreciated that when test results are maintained over a period of time that the observed trends/variances in test measurements may well act as an indicator of containment seal health. Clearly tests should be conducted at regular intervals however it is left to the various sites to determine 'how regular'. Since site conditions vary so much then the process conditions (hot/cold, condensing/non-condensing, clean/dirty etc.) plus the history of the equipment (how often seals have failed in the past) should all be considered. A further issue would be the actual location of the equipment along with the consequences of primary seal failure with loss of containment seal integrity are also prime factors. Clearly the risks associated with process fluid leakage to atmosphere are a primary reason for containment seal selection over (say) single seals and thus the assumption should be that process fluid loss is undesirable/unacceptable where it follows that periods should be relatively short. In the absence of other data then an initial period of 1 month for new equipment should be adopted with this period adjusted accordingly as confidence in the test protocol is realised.

Commissioning tests are a useful indicator for future site integrity tests. While a newly installed seal should be in optimum sealing condition conducting a site test before it is put into use will enable site engineers to study the seal and devise a suitable test protocol. Clearly this will enable the effects of the piping plan and its influence on test results to be understood so that the subsequent site tests can reveal the true integrity of the containment seal.

Regardless of the particular duty and conditions it is generally accepted that containment seal site integrity tests (static or dynamic) should be conducted at regular intervals.

So far as the actual test are concerned then the following addresses some of the issues associated with each type of test.

#### *Static Site Integrity Tests*

In the absence of the seal vendor providing suitable instructions for static testing the containment seal then the following steps should be taken once the test conditions have been approved.

- Identify the test chamber (this may or may not include parts of the piping plan/system).
- If the pump is void of pressure then ensure that the inboard seal design is capable of pressure reversals up to the desired seal integrity (or alarm verification) test pressure.
- Isolate the containment seal test chamber.
- Make sure that the seal test chamber is drained.
- Make a note of the location conditions around the seal (pump pressure & temperature plus ambient conditions).
- Verify the primary seal leakage over the test period (An agreed/acceptable pressure change should already be identified).
- Assuming the previous step is satisfactory then introduce test gas to the test pressure into the containment seal test chamber to the designated test pressure.
- Record the pressure change over the test period and confirm that this is within the agreed range.
- Restore the seal and system to its normal standby condition awaiting subsequent service.

The question often arises regarding how often should the site integrity tests be conducted. Clearly site requirements will play an important role in test frequency because a static test dictates that the equipment is taken out of service for at least the duration of the test. In situations where there are more pumps than what are required to maintain plant activity this may not be an issue however on strategic pieces of equipment where there is no back-up/standby units the integrity tests may require that plant activity ceases for the duration of the test. Additionally the consequence of process fluid escape should be considered since periodic integrity tests are the best way to ensure that containment seals will function correctly in the event of a primary seal failure. In the absence of historical data a starting point of testing every month should be considered as the maximum period between integrity tests.

There should also be an additional test to verify that the pressure alarm is working. In the above test the pressure transmitter/alarm may not be in the test chamber and hence additional steps need to be taken to ensure that the pressure transmitter/alarm can be exposed to the test gas and then be isolated so that the test can be conducted. A typical alarm functionality test would be similar to the one outlined above namely that the test chamber should be isolated and drained before introducing the test gas until it exceeds the designated alarm value. Alarm activation would signify pass/fail.



### *Dynamic Site Integrity Tests*

The merits of performing a dynamic integrity test are debatable. The first thing to appreciate is that while the seal model will have undergone API type qualification test that the pass criteria at the end of the qualification test is relaxed for the static air test and there is no fail criteria specified for liquid leakage in the liquid phase of the test is specified either. Similarly when a seal receives a factory integrity test this is static and not dynamic integrity test that is undertaken hence there is no basis on which to establish suitable test conditions and parameters for a dynamic site integrity test. It also needs to be appreciated that most of the static test considerations (stated above) also apply (isolating the seal system and introduction of test gas etc.) plus there are additional considerations relating to contacting and noncontacting seal designs. These factors all combine to make establishing a suitable test specification with pass/fail limits a complex issue.

Assuming that a dynamic site integrity test is conducted then isolating the seal and introducing a test gas into the containment seal chamber is not without issue. This is because even a small length of pipe forms part of the test loop and effectively becomes a 'test vessel'. In this respect it is fundamentally no different to static integrity testing. The isolated containment seal chamber will be subject to 'normal' leakage across the primary face effectively being an inlet to the containment seal chamber 'Normal' leakage from the containment seal effectively becomes the outlet. The inlet conditions (dictated primary seal cavity conditions i.e. process fluid pressure and temperature) will be different from one site application to another (assuming that the exact seal cavity conditions for any given application are actually known). Likewise the condition of the primary seal interface will have a strong influence on inlet conditions because pressure (differential), heat generation and leakage rate plus heat soak from the pump itself will all affect the test.

The actual contacting containment seal face design will also influence the test. In the case of a contacting design introducing the test gas at a given pressure will increase the load on the faces and hence the heat generated by the seal will increase accordingly. This could actually have a detrimental effect on the seal because the additional heat could produce additional wear due to increased load.

On seals where the containment seal is noncontacting the lift generation mechanism requires that gas flows across the face and hence leakage is an inherent aspect of seal performance. This means that the pressure within the pressurised containment seal cavity will reduce because of the way that the seal works. It follows that to determine what proportion of the leakage is normal and what is seal deterioration is extremely difficult to identify and hence setting pass/fail criteria is complex.

Given the complexities of a pressure based test method a flow based test technique could be adopted. This type of test would still require that the containment seal chamber is isolated but instead of introducing a test gas the chamber is left to fill with process fluid that leaks across the primary faces. Clearly the physical properties of the process fluid and the pumping conditions will be influential but the actual condition of the primary seal faces will strongly influence test results. In such tests as primary leakage enters the containment seal cavity the pressure will begin to rise and hence the rate at which the pressure increases will indicate the integrity of the containment seal. As described above the increase in pressure may overload a contacting containment seal and for a noncontacting design the pressure rise is offset by the normal leakage at the interface. Again the expected outcome is difficult to predict from such a test and hence a secondary measure may be to test seals in conjunction with an emissions test where atmospheric leakage also forms part of the test protocol. A further issue with this test method relates to the heat generated in the event of face contact. Irrespective of whether it is normal (contacting designs) or undesirable (noncontacting designs) the additional heat that is generated (from two sets of faces) in the absence of inert buffer gas would dictate that the isolated containment seal cavity would fill with process liquid/vapours. The consequences of this issue need to be carefully considered since it is a situation that is not without risk.

If dynamic site integrity testing is considered to be necessary then it is advisable to consult seal vendors to develop a suitable test procedure. Once a test specification has been devised it is also advisable to conduct a 'benchmark' test during the commissioning phase as this will not only identify the results that can be expected in subsequent integrity tests but also ensure that the test procedure is verified under controlled circumstances.

### **SUMMARY**

Given that there are two different seal designs, two different types of process fluid leakage, several different options for containment seal inlet and two for outlet the permutations are numerous and hence cannot be fully explained in this document. A more practical method to assess the various containment seal options is to construct a matrix where appropriate comments are stated so that these options can be addressed collectively. The matrix and associated comments are shown in table 2 and 3.

TABLE 2- Containment Seal Operation Matrix					
	Piping Plan			Contacting Containment Seal	Noncontacting Containment Seal
Process Fluid	Inlet	Outlet	Interface Fluid	Comment See Table 3	Comment See Table 3
Condensing	71 (None)	75	Process Vapours/Liquid	2, 4, 5, 6, 7, 10, 11,, 13,	1,4,5,6,7,10,11,12,13
		76	Process Vapours/Liquid	1,5,6,7,20	1,4,5,20
		None	Process Vapours/Liquid	1,17,6,15,10	1,17,15,10,11,12
	72 (N2)	75	N2	3	3
	72 (Air)	75	Air	1,14	1,14
	72 (Steam)	75	Steam	8,9,15, 18,10	10
		Other	Steam	1,15,17,19	1,17,19,11
Non-condensing	71 (None)	75	Process Vapours	2,15,7,10	2,10,11,12
		76	Process Vapours	2,15,	2,10,11,12
		None	Process Vapours	1,17,6,7,15,10	1,17,15,10,11,12
	72 (N2)	76	N2	3	3
		None	N2	1,17,15	2,12
	72 (Air)	76	Air	1,14	1,14
		None	Air	1,14	1,14
	72 (Steam)	76	Steam	18,15	16,18
		None	Steam	1,15,17,19	1,17,19

It should be noted that all of the entries in the matrix would be classified as “containment seals” since they all have designated API 682 piping plans however many of the entries have facets that would make them unreliable in service and should only be used under specific circumstances. An additional misnomer is the view that just because a seal has a piping plan that it must be reliable whereas in some instances nothing could be further from reality. In this respect many of the containment seal permutations stated in table 2 are unlikely to ever reach the objective 25,000 hour operation life stated in API 682. Given that the containment seal must be capable of preventing process fluid from escaping in the event of a primary seal failure the API 682 25,000 hour objective should not be overlooked. Just because a containment seal is not seen to be leaking does not mean that it will function correctly as a containment seal in the event of a primary seal failure. In this respect users of containment seals are advised to conduct routine integrity checks on containment seals.

API 682 remains the most informative document relating to mechanical seals, their design, usage and support systems. The procedures in this standard can be put to good use however misinterpretation and incorrect application of guidelines can dictate unreliable mechanical seal performance in the field. This is particularly evident when containment seals are being specified because the numerous options stated for these seals can result in misapplied technology resulting in premature failure and containment functionality.

TABLE 3- Containment Seal Operational Issues	
	Comment (See Table 2)
1	Unsuitable
2	Conditionally acceptable/caution
3	Optimum choice
4	Unstable Fluid Film
5	Contaminated Fluid Film
6	Additional heat generation
7	Coking / Polymerising potential
8	Steam trap required
9	Contaminated condensate from steam trap.
10	Debris/scaling/residue on seal parts
11	Grooves clog
12	Local/site fugitive emissions limits may not be contained
13	Performance limited by extent & nature of process fluid
14	Hydrocarbon oxygen mix in seal chamber creating explosive atmosphere
15	Accelerated containment seal wear
16	Contact if steam is wet
17	Containment Seal Chamber will become over pressurised
18	Steam in Flare
19	Steam dead ended - may condense in containment chamber
20	Condensate is unable to exit via a flare type system (gravity)

No containment seal should be specified for a duty without all modes of operation being considered, a user cannot simply expect all containment to operate with equal reliability and integrity regardless of the duty, seal type and piping plan. In this respect normal operation, transient effects, primary seal failure, containment seal failure and catastrophic failures (both faces failed) need to be thoroughly assessed.

Finally the most important thing to note in all of the above is that regardless of the type of containment seal or the piping plan/system; all that an integrity test really demonstrates is that the seal is still functioning correctly at that point in time. Clearly the more often the tests are conducted will increase confidence in the containment seal but in situations where containment seals repeatedly fail integrity tests then alternative sealing solutions should be considered.

## CONCLUSIONS

The following should assist in the selection and usage of containment seals.

- A correctly selected containment can provide an effective means of limiting process fluid leakage to atmosphere in the event of a primary seal failure.
- Containment seals along with suitably designed support systems (piping plans) are an effective means of minimising emissions.
- Contacting containment seals should be used with caution when no buffer gas is available.
- Noncontacting containment seals should not be used when no buffer gas is available.
- Plan 72 buffer gas provides the containment seals with a controlled operating environment.
- Plan 72 buffer gas provides a suitable datum from which alarm protocol can be established.
- Plan 72 buffer gas systems provide a suitable means of preventing emissions.
- Plan 72 buffer gas systems provide a suitable means of reducing debris and subsequent damage to secondary seal faces.

- Plan 72 buffer gas systems should only be used in conjunction with an appropriate outlet piping plan.
- Periodic site integrity testing of containment seals is advisable to ensure containment integrity is provided in the event of a primary seal failure.
- Care must be taken to account for the primary seal conditions and the attached system effects when conducting site integrity tests.

## CASE HISTORIES

### *Case 1*

At a petrochemical site a containment seal was fitted to a Butadiene pump duty at 8barg pressure, temperature of 45°C and rotating at 2950rpm. The seal had a plan 71 inlet with no outlet piping plan however a pressure gauge and a (manually operated) valve was fitted to the gland so that the leakage that collects in the containment seal cavity could be vented/drain. During normal operation the valve was normally closed until a pressure was registered on the pressure gauge thus signaling that the collected leakage required evacuating.

The seal had been in service for several years and the emptying sequence had been conducted on numerous occasions. In the period leading up to failure no pressure increases in the containment seal cavity were noted and it was assumed that all was operating well up to the point at which large amounts of process fluid started leaking without warning. Fortunately the equipment was taken off line before a major incident occurred however a near miss investigation was launched.

When the seal was removed it was noted that all of the containment seal and containment seal cavity surfaces were covered in residue to the extent that the gland port for the pressure gauge had completely blocked. This meant that the pressure gauge reading was incorrect and the pressure increase due to leakage was undetected. Given that the containment seal design was contacting the seal face overloaded due to the increase in pressure (and temperature) and when the primary seal failed the containment seal was inoperative thus high leakage occurred. The consequences of not having a buffer sweep inlet and suitable outlet meant that process leakage residue contaminated the cavity surfaces and hence gland port blockage occurred. Given also that there was no site integrity test procedures meant that the worsening conditions were not detected and so failure/leakage occurred without warning. Note that since the pressure gauge was unable to function and that there was no site integrity test then the chances are that the containment seal was not in an operable condition for quite some time.

The pump was refitted with a noncontacting containment seal adopting plan 72/76 systems and a site testing protocol was implemented. No similar occurrences have been reported.

### *Case 2*

At an oil and gas producers site a noncontacting containment seal was fitted to a condensate pump duty at 12barg pressure, temperature of 88°C and rotating at 2980rpm. The seal had a plan 23 (primary seal cavity cooling), plan 76 outlet with a plan 61 quench. The unit suffered from poor reliability however no major incidents had occurred. A detailed seal investigation showed deterioration to the containment seal faces which was shown to be due to liquid ingress from the containment seal cavity. The contamination was due to process fluid condensing in the containment seal cavity due to it not being able to exit via a plan 76 route. On this occasion the physical location of the pump (elevation) meant that a plan 75 could not be fitted and hence alternative technology (a plan 53B dual pressurised seal was installed) but it demonstrates a situation where the wrong exit piping plan was selected for a duty and this resulted in poor seal longevity.

## NOMENCLATURE

API = American Petroleum Institute  
MAWP = Maximum Allowable Working Pressure

## REFERENCES

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- 2 Bowden, P. E., 2015, The Development of API 682 4<sup>th</sup> Edition. Asia Turbomachinery & Pump Symposium (2016) [Ref 2]
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